EXH. DJL-5 (Apdx. B)
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: DAVID J. LANDERS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-240004** **Docket UG-240005**

APPENDIX B (NONCONFIDENTIAL) TO THE FOURTH EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF

DAVID J. LANDERS

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

Grid Modernization: Automation

Corporate Spending Authorization (CSA)

Date Created:	Friday, February 10, 2023
Discretionary/ Non-Discretionary:	Discretionary
Multi Year Rate Plan:	Programmatic
Equity Impact:	Yes
Strategic Alignment:	Operate the Business-Reliability
Estimated In-Service Date:	Sunday, December 31, 2028
Current State (Business Need):	PSE's reliability performance relative to duration of outages has exceeded the UTC SQI since 2019 and with a few exceptions of meeting that benchmark is trending upwards. Outage frequency has met the UTC SQI benchmark with the exception of 2021 for the first time, but like SAIDI is trending upwards. PSE has had automation on the transmission system since 1970 but the dated technology only provides restoration to a narrow set of substation outage conditions. PSE has had supervisory and monitoring SCADA technology on all 268 substations for many years, but in early 2000's began furthering the capability for control. By the end of 2020, 123/268 substations have SCADA control technology. With the advancement, PSE began deploying automation on the distribution system in 2016 but business practices have matured slowly and the technology has leverage EMS the transmission monitoring system putting more cost burden and resource on transmission operators to monitor. PSE has deployed automation on 94 circuits by the end of 2020. The advance of ADMS, the transition of distribution SCADA to this new tool, and an investment in Reclosers, PSE is positioned to aggressively launch towards automation. Industry norm deploys automation on transmission and distribution circuits address reliability performance. With the advent of growing electrification, customer expectations regarding power quality and reliability will continue to increase as they depend on electric vehicles and lack traditional natural gas energy to support heating and other life needs. With the implementation of ADMS and transition of SCADA devices from EMS to this new tool, PSE is positioned to implement the next technology of automation fault location, isolation, and service restoration ("FLISER") schemes that will dramatically reduce CMS, SAIDI, and SAIFI by reducing the number of customers experiencing a sustained service interruption (greater than 5 minutes) from any one outage event.

PUGET SOUND ENERGY

Grid Modernization: Automation

Corporate Spending Authorization (CSA)

Desired State (Proposed Solution):	New fault indicators were piloted on the transmission system and configuration tested in 2021. With operations practices now established, PSE will deploy this advanced automation on 68/173 transmission lines. PSE will install new reclosers on 433 circuits through 2034 (and replace 125 oil filled reclosers) along with further progress towards completion of 145 substations with SCADA, PSE will deploy automation on 532 (more) distribution circuits, prioritized by highest CMI benefit and coordinated with implementation of the voltage reduction program. As automation technology is deployed, asset issues such as pole replacement is addressed as well.

PSE PUGET SOUND ENERGY

Grid Modernization: Automation

Corporate Spending Authorization (CSA)

Outcome/Results (What are the anticipated benefits):	The 2021-2026 plan to complete SCADA control technology at 115 substations will that by itself allow system operators to control switches and reclosers which avoided 32.5M CMI. The 2021-2036 plan to deploy 558 reclosers will avoid 12.87M CMI. The 2021-2037 plan to deploy distribution automation on 532 circuits will avoid an additional 21.56M CMI. And the upgrade transmission automation on 75 circuits between 2021-2036 will avoid 31.2M CMI. A total of almost 98M CMI or 81 SAIDI minutes.

PUGET SOUND ENERGY

Grid Modernization: Automation

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Dependencies: No

Dependencies comment: None.

Escalation Included: No, escalation has not been included.

Total Estimated Costs: $350,980,000

Estimated Five Year Allocation:

Funds Type	ID	Line Item Description	Previous Years Actuals	Fiscal 2024 Requested	Fiscal 2025 Requested	Fiscal 2026 Requested	Fiscal 2027 Requested	Fiscal 2028 Requested
Capital	W_R.10006.01.01.03	E Substation SCADA CEIP	$ -	$ 14,080,000	$ 14,080,000	$ 13,840,000	$ 14,255,200	$ 13,200,000
O&M	79201	E Substation SCADA CEIP	$ -	$ -	$ -	$ -	$ -	$ -
Capital	W_R.10006.01.01.08	E Substation SCADA (Non-CEIP)	$ -	$ 7,920,000.00	$ 7,920,000.00	$ 7,785,000.00	$ 5,018,550.00	$ 2,700,000.00
Capital	W_R.10009.08.02.12	E OH Syst Rel Upgr Reclosers Dist	$ -	$ 3,500,000.00	$ 3,500,000.00	$ 3,000,000.00	$ 3,000,000.00	$ 3,200,000.00
Capital	W_R.10006.01.01.04	E Trans Automation	$ -	$ 4,500,000.00	$ 4,500,000.00	$ 4,000,000.00	$ 4,120,000.00	$ 3,800,000.00
Capital	W_R.10009.12.03.01	E Distribution Automation Dist	$ -	$ 20,900,000.00	$ 28,000,000.00	$ 35,000,000.00	$ 36,050,000.00	$ 26,400,000.00

Incremental O&M: Both

Qualitative Benefits: The primary benefit of these automation technologies is reliability and avoiding long duration outages. Additionally, they provide operational flexibility for operators.

Quantitative Benefits:

Quantitative Benefits	Benefit Type	Previous Years	Fiscal 2024	Fiscal 2025	Fiscal 2026	Fiscal 2027	Fiscal 2028	Fiscal 2029	Remaining Costs	Life Total
Reliability - Avoided CMI	Other	$ 220,666,000	$ 110,333,000	$ 110,333,000	$ 110,333,000	$ 51,550,000	$ 51,550,000	$ -	$ -	$ 654,765,000

Risk Summary:

Project risk includes permitting and operational practice changes as operators get comfortable with operations that occur with no eyes on in the field. Determination of acceptable lag and response will be methodologies to work through.

Benefit risk is minimized as they are realized when completed. At the point, PSE's deployment is unique for every circuit which limits speed of deployment. With standardization PSE maybe able to deploy faster which will bring benefits faster.

System risk is unaddressed reliability in one of the least expensive ways possible. PSE would continue to rely on an outdated method of automatic switching which has shown limitations in its' ability to restore substations following a single transmission line fault. Other alternatives include enhanced vegetation management, widening transmission corridors, building new transmission lines or installing transmission breakers within substations, which all have much higher costs and complexities in attaining the desired results. Easement acquisition and substation footprint increases are some of the complexities that prevent some of these alternatives from becoming cost effective and implementable. If DA FLISR is not implemented, PSE customers will experience outages that could have been prevented or shortened by DA FLISR schemes. Automation does bring perceived risk as operators and field become more comfortable with this technology, concerned that automation could close into an unsafe condition.

PUGET SOUND ENERGY

Grid Modernization: Automation

Corporate Spending Authorization (CSA)

Change Summary:

Planning Cycle	Change Summary	Last Update Date
2022 Baseline Cycle	This CSA has been migrated into the EPPM tool at go-live as part of the Phase 1 EPPM implementation effort. The projects in this CSA were previously approved for the 2023-2027 capital plan. Please refer to the original CSA document for additional information (if available.)	2/10/2023
2023 Cycle 1	Updated with last business plan information	3/16/2023

PUGET SOUND ENERGY

Grid Modernization: Automation

Corporate Spending Authorization (CSA)

Approval History:

Approved By	Date Approved
Approved by Cost Center Owner: Lambert , Ryan	3/30/2023
Approved by Cost Center Owner: Lambert , Ryan	4/3/2023
Approved by Director Sponsor: Landers , David	4/7/2023
Approved by Executive Sponsor: Jacobs , Josh	4/8/2023
CSA Status changed to Approved	4/8/2023
Approved by Cost Center Owner: Shrum , Bailey	12/4/2023
Approved by Director Sponsor: Shrum , Bailey	12/4/2023
Approved by Executive Sponsor: Shrum , Bailey	12/4/2023
CSA Status changed to Approved	12/4/2023
Approved by Cost Center Owner: Lambert , Ryan	1/29/2024
Approved by Director Sponsor: Landers , David	1/29/2024
Approved by Executive Sponsor: Jacobs , Josh	2/2/2024
CSA Status changed to Approved	2/2/2024

DISTRIBUTION AUTOMATION - FLISR

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Distribution Automation Fault Location, Isolation, and Service Restoration (DA FLISR) plan will expand automation capabilities to PSE distribution circuits, through the installation and/or upgrade of equipment and other system components as required.

2. BACKGROUND

According to a US DOE study titled 'Distribution Automation Results from the Smart Grid Investment Grant Program' written in September 2016, DA FLISR reduced CMI by 53%, SAIFI by 17% to 58% for the feeders which DA was installed.

DA FLISR automates outage restoration on PSE's distribution grid by using sensors to locate faults, remotely operate switches to isolate faulted sections and to restore power to the non-faulted sections. The DA FLISR system collects information from grid devices and determines the optimal switching to restore power to the largest number of customers in less than five minutes. The faulted section will still remain without power until crews can repair the damage.

DA FLISR has existed within PSE's system in different forms since the 1990s for customer funded targeted applications. GE's Prologic controller software was utilized, but became obsolete and required heavy manual maintenance for system updates and reconfigurations.

In 2016, a pilot was fully tested, proven and launched to replace the obsolete GE Prologic controller with a new computer control system, called Yukon Feeder Automation (YFA), to help orchestrate the self-healing automation. The first automated circuits under this plan were enabled in 2016 and new automated circuits continue to be implemented using the same control system. PSE's Advanced Distribution Management System (ADMS,) currently in development, may replace YFA as the FLISR control logic in the future.
As of the end of 2022, 122 circuits have DA FLISR capabilities enabled.

Since 2018 there have been 185 DA FLISR scheme operations on PSE's distribution system with the potential to save 23.8 million CMI. Of the 185 operations, 131 were considered totally successful with an additional 11 being partially successful. Due primarily to communications failures and modeling errors, actual CMI savings were approximately 60% of the total possible savings. In 2022 - 29 successful DA FLISR operations saved approximately 3.20 SAIDI minutes. Thus far in 2023 successful DA FLISR operations have saved approximately 1.63 SAIDI minutes. As experience is gained with the deployment and operation of this technology, the successful operation percentage will rise as shown by an increasing operation success rate since 2018.

3. STATEMENT OF NEED

PSE is committed to providing safe, reliable service to our customers. PSE is also integrating initiatives to modernize the grid. Grid modernization includes implementation of new technologies and devices that, when strategically deployed, can reduce customer outage minutes, through automated fault location, isolation and service restoration.

3.1. Need Drivers

- **Grid Modernization –**
  - **Reliability** – Strategic deployment of the DA FLISR schemes will reduce CMI, SAIDI and SAIFI by reducing the number of customers experiencing a sustained service interruption from any one outage event. Distribution SCADA reclosers, deployed by this plan, provide an increased ability of the distribution system to quickly and automatically respond to and switch around an outage event.
  - **Resiliency** - The ability to automatically and remotely operate reclosers provides PSE with the capability to quickly respond to and restore outages during extreme weather events and other emergencies.
  - **Smart and Flexible -** The addition of smart devices on the distribution system, such as the SCADA reclosers and voltage support devices, deployed by this plan, provide increased grid visibility and control to support grid modernization initiatives and the planning and management of an increasingly complex distribution system.
  - **Safety -** The increased ability to monitor and control the distribution system, provided by this plan, improves safety through the ability to remotely set Hot-Line Work Switch (HLWS) which is used to de-energize the circuit as rapidly as possible if an accident happens during line construction or maintenance. Increased monitoring will also provide the ability to quickly locate and isolate faults and roll trucks directly to the identified location.

3.2. Equity

PSE evaluates equity in the planning process with consideration of the four core tenets of energy justice: Recognition Justice, Procedural Justice, Distributional Justice, and Restorative Justice in various steps of the process.

As specific studies are performed and projects proposed to further a business plan, planners review system, customers, and now equity data to recognize the specific customer burdens, whether there are highly impacted or vulnerable customers that are or will be affected by addressing the specific business need. Planners must prioritize where to focus study each year, thus the full understanding of the historic and ongoing inequities for the entire business plan is extrapolated at this time, maturing over time which greater tools and data.

PSE is building process and tools to enable procedural inclusion in defining the need and solutions through engagement with specific communities and community based organizations, increasing understanding of local needs and consequences to inform specific study development as well as options to address need. Maturity in where and how this occurs will increase over the next several years. Business plans will be updated as informed this collective engagement to reflect broader equity benefits and burdens as this engagement increases over time.

As specific projects are proposed, PSE investment decision optimization tool captures equity benefits. An optimized portfolio of projects across many business plans ensures the distribution of benefits and burdens are spread across all segments of the community and aim to ensure that marginalized and vulnerable communities do not receive an inordinate share of burdens or are denied access to benefits. As an initial step, PSE leverages Customer Benefit Indicators ("CBI") and information established as part of the 2021 Clean Energy Implementation Plan ("CEIP") to identify an equity framework to evaluate system projects. The CBI approach was developed through an iterative process that was coordinated with the Equity Advisory Group. These CBI span the core tenets of energy justice and provide a framework to evaluate the comparative equity benefit of each solution alternative considered. Refer to Table 1 for a brief description of the CBIs that address equity and the applicable benefits for the Distribution Automation - FLISR program. PSE will continue to adjust and refine equity consideration in projects when necessary as the process continues to mature.

Projects will be evaluated on each CBI category and a total equity benefit score will be provided.

Table 1: Equity Applicable Benefits

Customer Benefit Indicator	Description	Program Applicable Benefit
Customer Energy Savings	Solutions that lead customers to use less energy, which leads to less energy that must be purchased and potentially a reduction in planned system upgrades.	No
Greenhouse Gas Emissions	Solutions that lead to a reduction of greenhouse gas emissions, either directly or indirectly	No
Enables Cleaner Energy	Solutions that either directly integrate DER on the system or enable the grid to more readily accommodate future DER.	No
Air Quality	Solutions that either directly eliminate the source of a common pollutant or reduce the risk that could cause a common pollutant to increase, such as enabling Electric Vehicle or DER adoption	No
Resilience	Solutions that address major event outages or harden critical facilities to prevent catastrophic events from creating long duration outages.	Yes
Cost Reduction	Solutions that identify least cost alternatives and therefore reduce costs for all customers	Yes
Clean Energy Jobs	Solutions that increase clean energy jobs by furthering clean energy technology application, as described in the CEIP	No
Home Comfort	Solutions that deploy residential energy efficiency in either a targeted solution area or by leveraging load reduction from system wide energy efficiency installations	No

The program attempts to annually address reliability and resiliency, specifically SAIDI, SAIFI, and CMI and is programmatically optimized based on total benefit value to cost. Specific program projects are identified based on total benefit to cost with named

communities receiving additional scored benefit based on vulnerable population designation and highly impact community characteristics, essentially ensuring investments are distributed appropriately to named communities.
Business plans in isolation do not address restorative justice, but continued planning process improvements which include considerations of data, tools, and documentation as well as operational practices will help to restore equity over time.

4. PLAN DETAIL

4.1. Plan Size/Population

The program will prioritize installing DA FLISR on circuits with high CMI on the feeder, that are mostly overhead feeder, that have Substation SCADA capabilities, and ideally do not have Conservation Voltage Reduction (CVR). Additionally circuits must not be heavily loaded so they can be tied to a neighboring circuit without causing an overload or exceed minimum voltage requirements most days of the year.

There are approximately 1,124 distribution circuits in PSE's electric system. At the end of 2022, there were ~122 circuits with DA FLISR enabled. This plan proposes to install DA FLISR on an additional 635 circuits. At the end of the plan, there will be ~757 circuits with DA FLISR enabled, or approximately 67% of all PSE circuits.

520 PSE circuits have been identified as "high CMI" circuits. These circuits have >150K average annual, all-in CMI (2018-2022), from outages originating on the feeder and can derive the highest benefit from DA FLISR implementation.

Of the 520 high CMI circuits, 108 circuits are on the Worst Performing Circuit (WPC) list and are part of the WPC Plan. Reliability benefits of DA FLISR schemes on these circuits are counted as part of the DA FLISR plan benefits but will be considered as solutions to meet the reliability improvements required by the WPC Plan.

Based on a review of completed DA FLISR projects it was found that approximately 1/2 of the circuits used within the DA FLISR schemes were not categorized as high CMI. This is because a high CMI circuit may not have available ties to other high CMI circuits and so must be backed up by a circuit(s) not in the high CMI group. This plan assumes that 1/3 of the circuits used in DA FLISR schemes will not be high CMI circuits.

Remaining DA FLISR Plan Circuit Population	
Total PSE circuits	1124
High CMI circuits *(defined as: PSE circuits with > 150K average annual, all-in CMI (2018-2022) from outages originating on the feeder)*	520
High CMI circuits that have/will have existing DA FLISR by end 2023	*(15)*
<u>Remaining High CMI circuits with no exist DA as of 2024</u>	**<u>506</u>**
Remaining High CMI circuits without a viable circuit tie (does not exist or violates N-1 capacity guidelines)	<u>(29)</u>
<u>Remaining Eligible High CMI circuit population for 2021-2027 DA FLISR plan</u>	**<u>477</u>**

Additional tie circuits necessary to implement DA on eligible High CMI circuit population (assumes 33% of plan circuits will need to tie to circuit not already within the plan)	158
Total Circuits included in the 2021-2030 DA FLISR plan	**635**

4.2. Proposed Completion Date

The proposed plan is to address the high CMI circuits through at least 2028. Monitoring of performance of the initial population of devices as well as re-analysis of circuit and system capabilities and needs will drive decisions on the deployment of DA FLISR schemes both within and beyond the plan.

4.3. Summary of Plan Benefits

The primary benefit of the DA FLISR plan is improved reliability for PSE customers. Significant reliability benefits, as shown in Section 4.4, will come from installing DA FLISR across our system. Annual non-MED CMI and SAIDI savings during the plan will vary depending on the make-up of the project portfolio for that year. The Table 1 below shows the summary of plan benefits specific to 2024-2025 budget portfolios.

In addition, this plan expects to improve resiliency during major weather events or during the loss of a transmission line or substation that are not included in the figures below. This benefit was not quantified, as the benefit for reliability substantially outweighed the benefit for resiliency for this plan.

Implementation of DA FLISR schemes will result in decreased travel times and improved situational awareness for PSE service personnel. This is achieved by better identifying and isolating the predicted fault location, providing the ability to remotely operate and control settings (i.e. HLWS during line work), further sectionalizing feeders and increasing system monitoring capability. This benefit was not quantified, as the benefit for reliability substantially outweighed the benefit of Operational efficiency and awareness for this plan.

4.4. Investment Decision Benefits

PSE employs an Investment Decision Optimization Tool (iDOT) to evaluate benefits of projects and optimize annual portfolios. The primary iDOT Benefits this plan addresses are:

- Outage Concern
- Flexibility
- Contribution to Strategy

Table 1. Summary of Plan Benefits, Population and iDOT B/C Score

	Total Projects	Total Plan ($M)	Number of Circuits	Non-MED CMI Saved	iDOT B/C Score
2025 -2026	20	$43.9	84	4,457,354	11.83

4.5 Estimated Costs

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Historical actual cost are $206k per circuit, future estimated cost are $558k per circuit based on projects planned for the 2024-2025 portfolios

DA FLISR project costs vary based on scope but average $558K per circuit. Total cost for the estimated 635 circuits included in this program would be approximately $354 million. OMRC is estimated to be 1.4% of project capital costs.

5. ALTERNATIVES

5.1. Solution alternatives

No Action/Other Action - If DA FLISR is not implemented, PSE customers will experience outages that could have been prevented or shortened by DA FLISR schemes. PSE will need to improve reliability through other, possibly more costly means such:

- Reliability solutions such as reconductoring to tree wire and underground conversion can improve reliability by preventing some outages totally but at a greater cost and higher project risk due to the need for more easements and larger permits.
- Installing additional traditional SCADA reclosers (increased circuit sectionalization) would also help to decrease the number of customers affected by any one event but does not have the ability to quickly restore customers through automated switching.
- Limiting the number of customers served per circuit (adding more circuits) would also help to limit the number of customers impacted by any one circuit outage.

5.2. Funding Alternatives

Increased Funding - With increased funding, benefits of reducing sustained interruptions for our customers could be achieved in earlier years. This is an evolving technology on PSE's system, so risks of accelerating deployment include potential for future costs associated with the need to convert more DA FLISR schemes from the current Yukon system to the ADMS system. Additionally, accelerated deployment could outpace the Substation SCADA plan implementation resulting in a lack of eligible circuits for the DA FLISR plan. Proper pacing of construction allows time to make adjustments to construction standards or deployment strategies as soon as issues become apparent, and allows for incorporation of new learning into our reliability improvement strategy.

Decreased Funding - Decreased funding would result in fewer DA FLISR schemes being implemented. PSE would see fewer outage reduction benefits and overall the corporate outage reduction metrics would see less improvement.

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Created/Modified By
10/25/2019	Initial Document - New plan template	Initial Document – Summarize historical plans	Sue Cagampang
4/22/2020	Revision	Updated scope, added budget and IDOT details	Sue Cagampang
5/5/2021	Revision	Update of program population and program timeframe	Sue Cagampang
7/13/2021	Used and Useful Policy guidance	Add alternative and cost information	Sue Cagampang
12/1/2021	Annual Review	Minor word and format changes	Sue Cagampang
12/1/2023	Revision	Updated program population and cost information Removed ISP Alignment, Added Equity section, minor word and format changes	Timothy LoPresto
12/5/2023	2024 MYRP Update	Updated Equity, Top 3 Primary iDOT categories, and Program Summary Table to align with 2025-2026 project submittals. Deleted the Benefit Allocation chart.	Krista Malmgren

7. SUPPORTING DOCUMENTATION

Document Name
FLISR Program Development Analysis, 2018, Jeff Kensok

TRANSMISSION AUTOMATION

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Transmission Automation plan provides automatic sensing and control to PSE's transmission lines to improve resiliency following transmission line faults. Transmission Automation uses sensors to identify and isolate the faulted section of transmission line and automatically performs switching to restore the non-faulted sections.

2. BACKGROUND

This plan builds on the Transmission SCADA plan of the past that used programmable logic controllers and traditional automatic switching schemes to restore as many substations as possible following a transmission line fault. While most customers are restored using traditional automatic switching following a transmission line fault, if the fault is in the wrong location on the transmission line, one or more substations may be left without power. Transmission Automation sensors monitor each line segment to intelligently sectionalize a faulted line section and restore the customers on the remainder of the transmission line.

The Transmission Automation plan began as a pilot plan out of the Smart Grid Technology Planning and Analysis Group in System Planning. Beginning in 2017, the project team set up the pilot, which included identifying the equipment to use, building a simulator in PSE's Snoqualmie Engineering Lab, and installing sensors in the field on two transmission lines.

More recently, PSE has developed the second generation of Fault Location, Isolation, and System Restoration (FLISR) for the transmission system which is called Transmission Line Automated Switching (TLAS). The overall goals of the second generation system are to have full coverage of each transmission line regardless of the number of distribution substations and to reduce the quantity of reclose-test actions needed to locate the fault. There are other benefits but these two are the highest priority.

In 2018, Horstmann Navigator Faulted Circuit Indicators (shown here) were installed on the two pilot transmission lines. These indicators transmit information that is used to determine fault directionality and location. Since installation, the Transmission Automation scheme on the two pilot transmission lines has been running in data gathering mode. This data has shown that the scheme correctly identified all faults, the availability of the system is greater than 98%, and that none of the components failed.

During this pilot period, the Substation Controls group has configured a duplicate Transmission Automation scheme in Snoqualmie Engineering Lab. In order to determine the durability of components used in Transmission Automation, the duplicate test scheme was subjected to over 15,000 faults. This successful trial demonstrated the system is ready for real-world control.

The plan has currently installed five TLAS schemes through 2022 in PSE's service territory to evaluate operation and benefits on all outage events of TLAS schemes through September 2023. As part of the pilot program, existing schemes will be upgraded to the latest technology based on lessons learned, including upgrading equipment and installing fiber communications infrastructure to improve operation of the schemes. PSE will continue to install TLAS schemes to evaluate benefits and improve reliability for eligible Transmission Lines. Prioritization and equipment utilized in TLAS schemes will be standardized as the program transitions to Business as Usual (BAU).

3.1 Need Drivers

- **Grid Modernization –** PSE's Automatic Switching methodology has not changed since implementation in the 1970s. On transmission lines with more than one substation, this dated technique can only restore all distribution substations automatically for a subset of possible outage scenarios. If a fault occurs outside this subset of scenarios, one or more substations must be restored by supervisory or manual action.

  After a permanent fault on a transmission line, Power Dispatchers sometimes have a difficult time determining the line section with a fault. Dispatchers must send Servicemen to patrol lines to identify the cause and location of the fault, leading to longer sustained outages.

- **Safety & Reliability –** Currently, traditional automatic switching schemes are installed on 95% of PSE transmission lines with at least one distribution substation. A traditional automatic switching scheme consists of motor-operated circuit switchers or disconnect switches that automatically open or close (without operator action) based on a loss of voltage or re-energization of a line section. There is no communication between switches, so each switch acts independently according to its local operating settings.

  Traditional automatic switching is most effective on lines with one or two distribution substations. Because each switch operates independently, the full scheme must be coordinated based on timing. Thus, it is only possible to coordinate a few switches per scheme. For lines with more than two distribution substations, this means that some substations will experience an outage for faults in certain line sections not covered by the traditional automatic switching scheme.

  Transmission Automation schemes rely on communication between switches and breakers, not time coordination. Transmission lines with substations not previously covered by traditional schemes will see a benefit from a new TA scheme.

  In event of an outage, lines would require patrolling to determine if any damage has occurred requiring repairs or if the line is safe and clear to re-energize. TA schemes reduce patrol times and will reduce safety exposure for the public, risk of wildfire and protect transmission assets.

- **Resiliency –** Transmission Automation contributes to resiliency during storm restoration through fault location and isolation. Transmission Automation sensors have LEDs that show which line section contains the fault. This can greatly assist the operations center and crews in identifying which line section to patrol during a storm.

  When substations are tripped out of service during storms, all of their distribution circuit breakers are opened to prevent accidentally energizing grounded distribution lines following the transmission fault. Servicemen must patrol and re-energize each of the distribution circuits after the substation is energized. Transmission Automation schemes coordinate all switches and breakers on a line to restore as many non-faulted sections as possible, leading to fewer substation outages.

  One way to determine how effective automatic switching schemes are at restoration is to look at the Transmission Reliability Index (TRI). This index measures the probability of restoring substations along a transmission line following a fault.

  The average TRI for transmission lines with at least two substations is 0.731 (73.1% probability of restoration following a fault). Due to intelligent identification and isolation of faults employed by Transmission Automation schemes, transmission lines with TA have a TRI of 1.0 (100% probability of restoration following a fault). Improving TRI is a major driver in reducing both frequency and duration of sustained outages.

- **Smart & Flexible** – Traditional automatic switching schemes rely on trial and error to determine which transmission line section contains a permanent fault. By closing into a permanent fault, the transmission line and connected equipment are exposed to high levels of damaging fault current. This can drastically reduce the lifespan and capability of the equipment.

  Transmission Automation schemes perform fault sectionalizing while the transmission line is de-energized. Only sections without a fault are re-energized, saving the equipment from exposure to another round of high fault current.

  The ability for the most recent Transmission Automation schemes to restore faults without Reclosing has additional Wildfire Mitigation benefit for transmission lines that are at risk for wildfire impact. In an event of extreme weather, the TA scheme can be activated in advance to de-energize portions of lines, if this is the appropriate course of action.

3.2 EQUITY

PSE evaluates equity in the planning process with consideration of the four core tenets of energy justice: Recognition Justice, Procedural Justice, Distributional Justice, and Restorative Justice in various steps of the process.

As specific studies are performed and projects proposed to further a business plan, planners review system, customers, and now equity data to recognize the specific customer burdens, whether there are highly impacted or vulnerable customers that are or will be affected by addressing the specific business need. Planners must prioritize where to focus study each year, thus the full understanding of the historic and ongoing inequities for the entire business plan is extrapolated at this time, maturing over time which greater tools and data.

PSE is building process and tools to enable procedural inclusion in defining the need and solutions through engagement with specific communities and community based organizations, increasing understanding of local needs and consequences to inform specific study development as well as options to address need. Maturity in where and how this occurs will increase over the next several years. Business plans will be updated as informed this collective engagement to reflect broader equity benefits and burdens as this engagement increases over time.

As specific projects are proposed, PSE investment decision optimization tool captures equity benefits. An optimized portfolio of projects across many business plans ensures the distribution of benefits and burdens are spread across all segments of the community and aim to ensure that marginalized and vulnerable communities do not receive an inordinate share of burdens or are denied access to benefits. As an initial step, PSE leverages Customer Benefit Indicators ("CBI") and information established as part of the 2021 Clean Energy Implementation Plan ("CEIP") to identify an equity framework to evaluate system projects. The CBI approach was developed through an iterative process that was coordinated with the Equity Advisory Group. These CBI span the core tenets of energy justice and provide a framework to evaluate the comparative equity benefit of each solution alternative considered. Refer to Table 1 for a brief description of the CBIs that address equity and the applicable benefits for the Transmission Automation program. PSE will continue to adjust and refine equity consideration in projects when necessary as the process continues to mature.

Projects will be evaluated on each CBI category and a total equity benefit score will be provided.

Table 1: Equity Applicable Benefits

Customer Benefit Indicator	Description	Program Applicable Benefit
Customer Energy Savings	Solutions that lead customers to use less energy, which leads to less energy that must be purchased and potentially a reduction in planned system upgrades.	No
Greenhouse Gas Emissions	Solutions that lead to a reduction of greenhouse gas emissions, either directly or indirectly	No
Enables Cleaner Energy	Solutions that either directly integrate DER on the system or enable the grid to more readily accommodate future DER.	No
Air Quality	Solutions that either directly eliminate the source of a common pollutant or reduce the risk that could cause a common pollutant to increase, such as enabling Electric Vehicle or DER adoption	No

Resilience	Solutions that address major event outages or harden critical facilities to prevent catastrophic events from creating long duration outages.	Yes
Cost Reduction	Solutions that identify least cost alternatives and therefore reduce costs for all customers	No
Clean Energy Jobs	Solutions that increase clean energy jobs by furthering clean energy technology application, as described in the CEIP	No
Home Comfort	Solutions that deploy residential energy efficiency in either a targeted solution area or by leveraging load reduction from system wide energy efficiency installations	No

The program addresses reliability and resiliency of the Transmission system and is programmatically optimized based on total benefit value to cost. Specific program projects are identified based total benefit to cost with named communities receiving additional scored benefit based on vulnerable population designation and highly impacted community characteristics, ensuring investments are distributed appropriately to named communities.

Business plans in isolation do not address restorative justice, but continued planning process improvements which include considerations of data, tools, and documentation as well as operational practices will help to restore equity over time.

4 PLAN DETAIL

4.1 Plan Size/Population

PSE has 173 transmission lines at 115kV and 55kV. Of these, 115 transmission lines serve at least one distribution substation and 109 of those lines have a traditional automatic switching scheme (95%).

PSE prioritizes TLAS on transmission lines that will maximize CMI benefits and includes consideration of substations with high customer counts, Transmission Resiliency Index, number of tapped substations on the transmission line, and customer equity considerations of customers on the line.

4.2 Proposed Completion Date

It is proposed that the Transmission Automation plan be funded to complete the upgrade from traditional automatic switching over the next 15 years. It is estimated that each line will cost an average of $850,000 to provide Transmission Automation to all substations on the line. An additional 2-3% per year is planned for OMRC.

It is expected to continue with the full spending level until completion of the program.

4.3 Investment Decision Benefits

PSE employs an Investment Decision Optimization Tool (iDOT) to evaluate benefits of projects and optimize annual portfolios. The primary iDOT Benefits this plan addresses are:

- Outage Concern
- Contribution to Strategy
- Flexibility

Table 2: Summary of Plan Benefits, Population and iDOT B/C Score

	Total Projects	Total Plan ($M)	Non-MED CMI Saved (#M)	iDOT B/C Score
2025-2026	22	$12.9	19.2 M	8.20

Estimated Total Costs

Baseline for future year cost estimate is $850k per line, which allows for variations in project scope, total number of substation devices per line, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project. With added fiber scope necessary to provide a sufficient communication network for TLAS operation, projected future cost estimates will increase by approximately 42% per scheme.

5. ALTERNATIVES

5.1 Solution alternatives

No Action – By not implementing the Transmission Automation Program, PSE would continue to rely on an outdated method of automatic switching which has shown limitations in its' ability to restore substations following a single transmission line fault. This would be a lost opportunity to gain valuable working experience with a new technology that provides a significant upgrade to the transmission system.

5.2 Funding alternatives

Increase Funding – An increase in funding would increase the number of TLAS schemes installed and move the program closer to completion. The program benefits increase with the number of active TLAS schemes. Increasing funding would lead to an earlier realization of these program benefits and an immediate reduction in CMI.

Decrease Funding – A decrease in funding would result in fewer active TLAS schemes and would increase the number of years required to install TLAS schemes on all applicable transmission lines. Program benefits would take additional years to be realized. PSE would continue to rely on an outdated method of automatic switching which has limitations in its ability to restore substations following a single transmission line fault.

The proposal is to install Transmission Automation schemes on PSE transmission lines, with more than one substation, over 15 years. This will reduce substation outages following a single transmission line fault.

Relying on traditional automatic switching is a failure to realize the reliability benefits of this new technology. In addition to the reliability benefits, transmission conductor and substation equipment are spared repeated exposure to damaging fault current.

The question of how long it will take to fully implement the plan is one of benefits versus budget. Simply, the more money spent on this plan, the greater the benefits.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
2/25/2016	Initial plan	Initial document	Reid Shibata
6/23/2020	Revision	Annual plan update	Carol Jaeger
12/1/2021	Revision	Annual plan update	Ben Walborn
9/30/2023	Revision	Annual Plan Update	Dan Rizzo
12/5/2023	2024 MYRP Update	Updated Equity, Top 3 Primary iDOT categories, and Program Summary Table to align with 2025-2026 project submittals	Krista Malmgren

7. SUPPORTING DOCUMENTATION

Transmission Line Priority Spreadsheet: X:\#1 T PLAN\7 System Wide\Transmission Automation\#Projects\Prioritization.xlsx

RECLOSERS

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

This plan will address the addition of new reclosers for reliability/sectionalizing purposes on a subset of PSE's 1,124 feeder circuits company-wide. Additionally, there are aging/obsolete (oil filled and Joslyn/SEL-351J) reclosers and sectionalizers planned for replacement. These specialized protective devices sectionalize and reduce the number of customers impacted by a permanent fault on the main line feeder.

2. BACKGROUND

In 2008, PSE commissioned a study by Quanta Technologies to prepare a 10 Year Distribution Reliability Improvement Roadmap. Quanta's final report in June 2008 presented a reliability roadmap that predicted the number of customer interruption minutes on the system could be reduced by approximately 50%. Among the numerous reliability improvement projects in the roadmap, was the highly cost-effective plan of installing new 3-phase line reclosers on circuits throughout the system. In 2016 PSE requested a study update to reflect the progress that PSE had made and to identify potential improvements to the distribution reliability improvement strategy for the next several years. The 2016 update focused on distribution reliability improvement strategies with emphasis on identifying ways to reduce SAIDI and SAIFI and to identify improvement solutions to improve PSE reliability indices. The 2016 updated study again emphasized that overcurrent protection options have a dramatic impact on reliability and are critical to consider within a reliability improvement project. Equipment considered within this category are fuses and reclosers.

A recloser is a three-phase reclosing device that, when sensing fault current, will quickly trip open. After an adjustable period of time (usually 10 seconds) the device will reclose (close again). If the cause of the fault remains the recloser will trip open and lock open with a minimum disturbance to the upstream customers on the feeder. If the cause of the fault cleared itself (temporary fault) the recloser will remain closed and power will be restored to all customers initially affected.

Most utilities pursuing significant reliability improvement rely heavily on the installation of new 3-phase reclosers. These devices dramatically reduce the impact of sustained faults on the main trunk line by not requiring the substation circuit breaker to lock out and interrupt all customers on the entire circuit, which results in an improved customer experience.

3. STATEMENT OF NEED

PSE's mission is to provide safe, clean and reliable energy service and is modernizing the grid to support this mission. This grid modernization includes implementation of new technologies and devices that, when strategically deployed, can reduce outages through fault clearing and reclosing (a form of automation). Smarter devices strategically located on the system, such as reclosers which record operations, can further assist planning analytics to develop a clearer understanding of the benefits of and the need for temporary fault clearing.

3.1. Need Drivers

- **Grid Modernization -**
  - **Reliability** – Strategic deployment of reclosers will reduce CMI, SAIDI, and SAIFI by reducing the magnitude/exposure of some outages and shortening some outages from sustained outages to momentary outages.
  - **Smart & Flexible** – It can be difficult to assess which outages of unknown cause are the result of a temporary fault. Reclosers can provide fault, indication and loading data that can be used to validate planning analytics around the impacts of temporary faults on PSE reliability metrics and inform future planning decisions. Also, with the installation of SCADA capable reclosers across the distribution system, PSE will be able to utilize the reclosers for distribution automation and provide an enhanced level of control, visibility and operational awareness for system operators via ADMS.

3.2. Equity

PSE evaluates equity in the planning process with consideration of the four core tenets of energy justice: Recognition Justice, Procedural Justice, Distributional Justice, and Restorative Justice in various steps of the process.

As specific studies are performed and projects proposed to further a business plan, planners review system, customers, and now equity data to recognize the specific customer burdens, whether there are highly impacted or vulnerable customers that are or will be affected by addressing the specific business need. Planners must prioritize where to focus study each year, thus the full understanding of the historic and ongoing inequities for the entire business plan is extrapolated at this time, maturing over time which greater tools and data.

PSE is building process and tools to enable procedural inclusion in defining the need and solutions through engagement with specific communities and community based organizations, increasing understanding of local needs and consequences to inform specific study development as well as options to address need. Maturity in where and how this occurs will increase over the next several years. Business plans will be updated as informed this collective engagement to reflect broader equity benefits and burdens as this engagement increases over time.

As specific projects are proposed, PSE investment decision optimization tool captures equity benefits. An optimized portfolio of projects across many business plans ensures the distribution of benefits and burdens are spread across all segments of the community and aim to ensure that marginalized and vulnerable communities do not receive an inordinate share of burdens or are denied access to benefits. As an initial step, PSE leverages Customer Benefit Indicators ("CBI") and information established as part of the 2021 Clean Energy Implementation Plan ("CEIP") to identify an equity framework to evaluate system projects. The CBI approach was developed through an iterative process that was coordinated with the Equity Advisory Group. These CBI span the core tenets of energy justice and provide a framework to evaluate the comparative equity benefit of each solution alternative considered. Refer to Table 1 for a brief description of the CBIs that address equity and the applicable benefits for the Recloser program. PSE will continue to adjust and refine equity consideration in projects when necessary as the process continues to mature.

Projects will be evaluated on each CBI category and a total equity benefit score will be provided.

Table 1: Equity Applicable Benefits

Customer Benefit Indicator	Description	Program Applicable Benefit
Customer Energy Savings	Solutions that lead customers to use less energy, which leads to less energy that must be purchased and potentially a reduction in planned system upgrades.	No
Greenhouse Gas Emissions	Solutions that lead to a reduction of greenhouse gas emissions, either directly or indirectly	No
Enables Cleaner Energy	Solutions that either directly integrate DER on the system or enable the grid to more readily accommodate future DER.	No
Air Quality	Solutions that either directly eliminate the source of a common pollutant or reduce the risk that could cause a common pollutant to increase, such as enabling Electric Vehicle or DER adoption	No
Resilience	Solutions that address major event outages or harden critical facilities to prevent catastrophic events from creating long duration outages.	Yes
Cost Reduction	Solutions that identify least cost alternatives and therefore reduce costs for all customers	No
Clean Energy Jobs	Solutions that increase clean energy jobs by furthering clean energy technology application, as described in the CEIP	No
Home Comfort	Solutions that deploy residential energy efficiency in either a targeted solution area or by leveraging load reduction from system wide energy efficiency installations	No

The program attempts to annually address the CMI of a circuit by improving reliability and is programmatically optimized based on total benefit value to cost. Specific program projects are identified based total benefit to cost with named communities receiving additional scored benefit based on vulnerable population designation and highly impact community characteristics, essentially ensure investments are distributed appropriately to named communities.

Business plans in isolation do not address restorative justice, but continued planning process improvements which include considerations of data, tools, and documentation as well as operational practices will help to restore equity over time.

4. PLAN DETAIL

4.1. PLAN SIZE/POPULATION

This plan proposes to install reclosers by applying planning criteria for prioritizing the most suitable sites for a new recloser installation or upgrade of an old/obsolete recloser in coordination with the Distribution Automation program. Priority will be given to areas with the highest CMI which is determined from the highest number of customers benefitting and highest numbers of outage events.

The number of estimated eligible reclosers was determined using the following criteria:

- Only install of circuits with at least 25% overhead conductor
- Circuit must have at least 0.5 miles of overhead conductor
- Circuit must have less than 2 existing reclosers
- Circuit must not have proposed or existing DA scheme
- Assume 80% of circuits that pass the above filters will be a suitable candidate for a new recloser
- Assumed 1 recloser per circuit that passes the above filters

Applying these filters and assumptions results in approximately 350 reclosers being installed on 350 circuits under this program.

4.2. PROPOSED COMPLETION DATE

The plan is currently proposed to run through at least 2028 to address locations where reclosers are feasible and beneficial. As of 2023 Planning estimates that ~350 circuits are eligible for a new recloser. Replacing obsolete or oil filled reclosers and sectionalizers will account for another ~45 reclosers for a total of ~395 reclosers.

Assuming program funding levels and installation costs stay consistent with recent years 33 reclosers can be installed or replaced per year. Evenly distributing new installations and replacements results in 29 new reclosers and 4 Joslyn/oil-filled replacements per year. At the rate of 33 reclosers per year all ~395 reclosers will be installed or replaced by 2034.

4.3. SUMMARY OF PLAN BENEFITS

Improved Customer Reliability -The primary benefit of this plan is improved reliability for PSE customers. Completion of new recloser locations is expected to result in the nonstorm (non-MED) and storm (All-In) related reliability benefits as seen in Table 1 below for the 2024-2025 portfolio. The added benefit of more data points in the field will provide increased situational awareness for PSE's operators and enable faster outage restoration.

Improved Customer Satisfaction/Experience - Improved reliability for customers will result in an improved customer perception of PSE as well as provide the value to customers of avoided outages. Increased reliability also has an overall public benefit when critical and public services are not disrupted, and commercial businesses can operate normally.

Reduce In-Service Failed Material and Environmental Risk – Replacing aging reclosers will reduce the likelihood of a recloser failing while in service. When an older style recloser fails there is no way of knowing the device is no longer functioning, resulting in faults passing through to the next upstream protective device. This leads to additional outage minutes for customers upstream of the failed device. Additionally, removing oil-filled reclosers from our system reduces the likelihood of an oil leak from the device, either due to age or outside force such as tree or car vs pole accident.

Improved Device Capabilities – New reclosers and controllers will have increased capabilities, such as SCADA, that the old devices don't have. SCADA enabled reclosers allow for remote operation, which is faster and will shorten outage times. A circuit with SCADA capable reclosers will reduce project execution risk if or when the circuit is included in a future DA-FLISR scheme.

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4.4. Investment Decision Benefits

PSE employs an Investment Decision Optimization Tool (iDOT) to evaluate benefits of projects and optimize annual portfolios. The primary iDOT benefits this plan addresses are:

- Outage Concern
- Flexibility

Table 2: Summary of Plan Benefits, Population and iDOT B/C Score

	Total Projects	Total Plan ($M)	Non-MED CMI Saved	iDOT B/C Score
2025-2026	**78**	$7.5	1,828,686	3.75

4.5. Estimated Costs

Electric System Planning estimated costs are generated based off historical costs on similar types of projects, allowing for variations in project scope, increase in project cost due to inflation, and added contingency to account for unforeseen conditions associated with the project.

Total estimated costs are based on the average historical cost of $90k capital per installation. OMRC is 4% of capital, or $3.5k per recloser.

Capital costs assume a 50 ft. pole is used for any new pole installation.

Total cost for ~395 installations (~350 new + replacement of ~45 obsolete) would be ~$36.9 million over ~10 years.

There are currently ~350 circuits identified as candidates for new recloser installations.

5. ALTERNATIVES

5.1 Solution alternatives

No Action: If the recloser plan is not implemented:

- The system will not see the benefits of reduced outage exposure (SAIDI) resulting from improved sectionalization for permanent faults.
- There is also the potential risk of customer dissatisfaction in areas experiencing outages due to breaker operations with unknown causes that could be reasonably addressed by this plan.
- More costly solution alternatives like the installation of tree wire or underground conversions may be required.

5.2 Funding alternatives

Increased Funding: With increased funding the benefits of reducing sustained outages could be achieved in earlier years. Pacing construction, however, allows time to make new installations part of a well thought out DA-FLISR implementation/deployment.

Decreased Funding: Decreased funding would result in fewer locations with recloser installations. Only areas with new installations would see outage reduction benefits and overall, the corporate outage reduction metrics would see less improvement.

6. PLAN DOCUMENT HISTORY

Date	Reason(s) for Update	Summary of Significant Change(s)	Created/Modified By
6/18/2020	Initial plan- New plan template	Initial Document– Summarize historical plans	Sam Di Re, PE
5/5/2021	Revised Funding	Revised Funding	Sam Di Re, PE
12/1/2021	Annual Review	Minor word and format changes	Sam Di Re, PE
12/1/2023	Revision	Added Equity, removed ISP and 5 year plan table	Timothy LoPresto
12/5/2023	2024 MYRP Update	Updated the Equity Table, Top 2 Primary iDOT Benefits, and the Program Summary Table to align with 2025-2026 project submittals. Deleted the Benefit Allocation chart	Krista Malmgren

7. SUPPORTING DOCUMENTATION

Document Name
RELIABILITY IMPROVEMENT ROADMAP: FINAL REPORT - PREPARED BY QUANTA TECHNOLOGY, JUNE 24, 2008
RECLOSER PRIORITIZATION
UPDATE OF 10-YR DISTRIBUTION RELIABILITY IMPROVEMENT ROADMAP: DRAFT REPORT - PREPARED BY QUANTA TECHNOLOGY, DECEMBER 20, 2016
APPLICATION OF OH DISTRIBUTION SECTIONALIZING DEVICES - PSE STANDARD 6300.0500

SUBSTATION SCADA

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

This plan will bring Supervisory Control and Data Acquisition (SCADA) capabilities to PSE's distribution circuits through equipment upgrades and microprocessor relay technology. SCADA implementation includes installation of controllers, relays, sensors, software and Information Technology (IT) upgrades for communication. These upgrades typically apply to the substation breakers on the 12.5kV distribution system, which enable data collection and communication between equipment in order to function automatically or be controlled remotely if needed.

2. BACKGROUND

PSE has approximately 267 distribution substations. These substations transform transmission level voltage (typically 115kV) to a distribution level voltage (typically 12.5kV) to safely deliver power to residential neighborhoods and commercial areas. These distribution substations are important electrical hubs and there are many different pieces of substation equipment (e.g. Breakers, Transformers and Relays) that send status updates, alarms and diagnostics data for Operators to monitor and control the system in real-time. In addition, this information allows planners to identify short and long-term deficiencies and propose system improvements to ensure a reliable and safe electrical grid.

SCADA is a communication system used to remotely monitor and control substation or field equipment. Key information, such as circuit breaker status and transformer loading, can be obtained almost instantly and transmitted to PSE's Control Area operations center. In order to enable SCADA capability at all PSE substations, much of the aging equipment that is directly affected will need to be replaced. The remaining vacuum type breakers will be replaced with new smart breakers, which include microprocessor relays. This in turn drives the replacement of aging control cables and older type Remote Terminal Units (RTUs), amongst other distribution related equipment in the substation.

2.1. Plan History

Late 1980's - PSE invested in an Energy Management System (EMS), which allowed Operators to visualize substation data. At the time, this was a new technology in the industry that many other utilities started to adopt. As the company gained familiarity with EMS, an early Distribution SCADA plan was initiated to add SCADA equipment to substations to provide transformer MW, MVAR, MVA, and single-phase distribution feeder amps back into EMS for visualization.

1990's – As PSE learned more about communication needs and additional benefits were evaluated, the Distribution SCADA Plan scope was revised to include three-phase feeder amps, as well as, feeder breaker status (Open/Close). Some breakers were retrofitted with new SATEC meters, while others were replaced with new circuit breakers with the meters built-in.

2000’s – In the early 2000’s, the Distribution SCADA plan was accelerated to upgrade approximately 10 substations a year, to bring these benefits to the remaining distribution substations. In the late 2000’s, distribution circuit breaker supervisory control was added to the scope of the plan. Some breakers were retrofitted with remote control switches, while others were replaced with new circuit breakers with the remote control capability.

2016 – In 2016, all distribution substations were planned to be upgraded to meet the intent of the original Distribution SCADA plan (feeder breaker three-phase amps and status, & transformer loading data). At this time, it was determined to continue the Distribution SCADA plan renamed as the Substation SCADA program. This included focus on adding supervisory control to the remaining distribution substations and feeder breakers while also enhancing SCADA equipment in the control house.

As of the end of 2022, approximately 142 of the 267 substations have SCADA capabilities on all distribution substation breakers. The plan aligns with the Internet Protocol (IP) SCADA plan as PSE extends its fiber network and upgrades communication panels in each substation control house to support the installation of new relays and SCADA enabled equipment. At the current rate of implementation, PSE will complete the implementation of SCADA on remaining 125 substations by 2035.

2021 – PSE’s clean energy goals encourage the adoption of Distributed Energy Resources (DERs) within PSE’s electric system. Substation SCADA facilitates increasing use of Distribution Automation (DA) for improved circuit reliability and resiliency. Additionally, increasing DA use facilitates the ability to operate and respond effectively to DER operations and the complexity that increases as more are added to a particular circuit or substation. Substation SCADA is needed to advance the combination of these two benefits in the deployment of microgrids. These capabilities are not possible without Substation SCADA. PSE could wait until each DER interconnects and then address SCADA and other enhancement needs. However, this approach will slow down operationalizing DERs and limit DER potential to offers that can afford higher interconnection costs.

3. STATEMENT OF NEED

The lack of supervisory control at distribution substations reduces the ability of system operators from operating the system in a timely manner to effectively reduce outage duration during an event, and the restoration of service to customers. Additionally, there can be multiple pieces of substation equipment that are at the end of their life, which can lead to additional reliability concerns. As DA becomes a wide-spread solution, there are necessary upgrades needed to provide SCADA capability to substation equipment which allows us to implement the automation solution successfully. SCADA enabled breakers will allow for improved fault detection and provide the ability to restore power to customers faster. In order for the DA plan to be effective and provide reliability benefits to the customers, it is necessary to have SCADA enabled breakers and equipment on the relevant circuits being upgraded under the DA plan.

3.1. Need Drivers

- **Grid Modernization –**
  - **Reliability** - The primary benefit of the Substation SCADA plan is improved reliability for Distribution circuits when aligned with Distribution Automation projects. The ability to remotely monitor and operate circuit breakers will allow System Operators to restore customers faster and reduce overall outage durations.
  - **Smart & Flexible** - Adding new smart breakers will provide the foundation of sensing and control for new advanced technologies, such as ADMS, DA FLISR and VVO, which will support System Operators to provide added flexibility to the system, improve reliability and enable customers to connect DERs.
  - **Resiliency –** Smart breakers combined with DA systems help detect and locate faults faster. Through new effective switching and protection schemes in place, PSE can restore power to customers faster and remotely. This improves resiliency by protecting the infrastructure from further damage and maintain service to our customers.

3.2. Equity

PSE evaluates equity in the planning process with consideration of the four core tenets of energy justice: Recognition Justice, Procedural Justice, Distributional Justice, and Restorative Justice in various steps of the process.

As specific studies are performed and projects proposed to further a business plan, planners review system, customers, and now equity data to recognize the specific customer burdens, whether there are highly impacted or vulnerable customers that are or will be affected by addressing the specific business need. Planners must prioritize where to focus study each year, thus the full understanding of the historic and ongoing inequities for the entire business plan is extrapolated at this time, maturing over time which greater tools and data.

PSE is building process and tools to enable procedural inclusion in defining the need and solutions through engagement with specific communities and community based organizations, increasing understanding of local needs and consequences to inform specific study development as well as options to address need. Maturity in where and how this occurs will increase over the next several years. Business plans will be updated as informed this collective engagement to reflect broader equity benefits and burdens as this engagement increases over time.

As specific projects are proposed, PSE investment decision optimization tool captures equity benefits. An optimized portfolio of projects across many business plans ensures the distribution of benefits and burdens are spread across all segments of the community and aim to ensure that marginalized and vulnerable communities do not receive an inordinate share of burdens or are denied access to benefits. As an initial step, PSE leverages Customer Benefit Indicators ("CBI") and information established as part of the 2021 Clean Energy Implementation Plan ("CEIP") to identify an equity framework to evaluate system projects. The CBI approach was developed through an iterative process that was coordinated with the Equity Advisory Group. These CBI span the core tenets of energy justice and provide a framework to evaluate the comparative equity benefit of each solution alternative considered. Refer to Table 1 for a brief description of the CBIs that address equity and the applicable benefits for the Substation SCADA program. PSE will continue to adjust and refine equity consideration in projects when necessary as the process continues to mature.

Projects will be evaluated on each CBI category and a total equity benefit score will be provided.

Table 1: Equity Applicable Benefits

Customer Benefit Indicator	Description	Program Applicable Benefit
Customer Energy Savings	Solutions that lead customers to use less energy, which leads to less energy that must be purchased and potentially a reduction in planned system upgrades.	No
Greenhouse Gas Emissions	Solutions that lead to a reduction of greenhouse gas emissions, either directly or indirectly	No
Enables Cleaner Energy	Solutions that either directly integrate DER on the system or enable the grid to more readily accommodate future DER.	No
Air Quality	Solutions that either directly eliminate the source of a common pollutant or reduce the risk that could cause a common pollutant to increase, such as enabling Electric Vehicle or DER adoption	No
Resilience	Solutions that address major event outages or harden critical facilities to prevent catastrophic events from creating long duration outages.	Yes
Cost Reduction	Solutions that identify least cost alternatives and therefore reduce costs for all customers	No
Clean Energy Jobs	Solutions that increase clean energy jobs by furthering clean energy technology application, as described in the CEIP	No
Home Comfort	Solutions that deploy residential energy efficiency in either a targeted solution area or by leveraging load reduction from system wide energy efficiency installations	No

The Substation SCADA Plan is programmatically optimized based on total benefit value to cost. Specific program projects are identified based total benefit to cost with named communities receiving additional scored benefit based on vulnerable population designation and highly impacted community characteristics toensure investments are distributed appropriately to named communities.

Business plans in isolation do not address restorative justice, but continued planning process improvements, which include considerations of data, tools, and documentation as well as operational practices will help to restore equity over time.

4. PLAN DETAIL

4.1. Plan Size/Population

As of the end of 2022, there are approximately **125 substations** requiring supervisory control for some or all breakers. This plan will ensure all PSE owned feeder breakers have supervisory control. Substation SCADA projects are typically prioritized based on multiple factors including failure history and number of customers impacted to provide benefit. However, it is also beneficial to prioritize based on coordination efforts with Distribution Automation projects on same circuits.

4.2. Proposed Completion Date

This plan has been accelerated to complete SCADA improvements on the remaining substations by 2029 in alignment with PSE’s clean energy goals. Delivery of this plan is based on crew availability per region and capacity to complete projects on time. Major challenges include being able to obtain multiple substation outages and the ability to pick up customers on the affected circuits, this could lead the grid to be less reliable while multiple substations are being picked up by neighboring substations.

4.3. Summary of Plan Benefits

Supervisory Control at the feeder breaker level provides reliability, operational flexibility and safety benefits.

- **Reliability** - The main driver for this plan is to reduce the duration of outages, giving System Operators the remote capability to restore customers faster.
- **Operational Flexibility** - Provides added operational flexibility to System Operators to operate breakers, turn on/off reclosing, and toggle HLWS remotely, when field personnel are not available. Substation inspectors do not need to be on site to obtain information or operate equipment.
- **Safety** – Supervisory control of individual feeder breakers allow operators to de-energize or isolate circuits, rather than entire substations, quickly in case of any safety issues in the field.

SMART breakers allows for enhanced planning analysis and post-fault evaluation.

- **Data Integrity** - Ability to acquire MW & MVAR data points at the feeder level to evaluate feeder-level power quality for optimal Capacitor Placement and future CVR/VVO prioritization.

- Microprocessor relays can estimate the location of faults, giving operators additional real-time information to quickly send servicemen to isolate trouble areas. The relays also provide post-fault recording data for use in Root Cause Analysis, to resolve unknown or other unique fault events.

Replacement of Communication Remote Terminal Unit (RTU) at the end of life.

- **Situational Awareness**- RTU failures can lead to a loss of visibility and control, leading to immediate unplanned use of field personnel to repair/replace the equipment, and 1-2 weeks of loss visibility and control. Updated Remote terminal units under the SCADA plan will provide improved situational awareness.
- **Data Quality & Integrity** - The upgrade to IP SCADA allows for faster and improved data transfers, as well as higher data accuracy and granularity.
- **Communication Quality** - The replacement of RTU will allow for a higher reliability of communication and an increased confidence in the success rate of Distribution Automation.
- **Operational Flexibility** - In addition, upgrading to IP SCADA provides the ability for remote engineering access to breaker relays.

4.4. INVESTMENT DECISION BENEFITS

PSE employs an Investment Decision Optimization Tool (iDOT) to evaluate benefits of projects and optimize annual portfolios. The primary iDOT Benefits this plan addresses are:

- Outage Concern
- Flexibility

Sub SCADA plans are entered into iDOT at a plan level based on available funding and portfolio project count. Each project has a certain amount of customers, which impacts the final Customer Minute Interruption (CMI) benefits that can be achieved at that substation.

Table 2: Summary of Plan Benefits, Population and iDOT B/C

	Total Projects	Total Plan ($M)	Number of Stations	Non-MED CMI Saved	iDOT B/C Score
2024-2025	37	$31.7	37	10,556,760	1.79

4.5. ESTIMATED COSTS

Average historical cost are not applicable to future projects due to the wide variability and complexity of improvements needed within each substation. PSE has historically used $500k as a baseline starting point to estimate future projects. Depending on scope and external factors, project costs can vary from $400k - $800k. Future cost estimates may vary due to inflation and added contingency to account for unforeseen conditions associated with each substation.

5. ALTERNATIVES

5.1. Solution alternatives

No Action – Lost opportunity to improve customer reliability and drive forward on Grid Modernization in a strategic and programmatic manner. Will not provide PSE the control to restore power quicker to customers and improve overall reliability.

One alternative to this proactive plan is to replace assets with SCADA enabled devices as they fail, leading to impacts to customer reliability during fault events.

Another alternative is to add SCADA enabled breakers without Supervisory control, which would still provide visualized load data in the Energy Management System (EMS) at a lower cost, but with no Supervisory control, the equipment could not be remotely operated to restore power to customers faster. This slows restoration time and reduces operational flexibility while also not improving safety by requiring substation personnel to directly operate the equipment.

5.2. Funding alternatives

Increased Funding – Increasing funding will allow for increased circuit eligibility for Distribution Automation-FLISR to be added. It will also increase System Operations' ability to control field equipment and improve situational awareness.

Decreased Funding – Decreasing funding will mean some of the coordinated circuits aligned with Distribution Automation-FLISR would need to be deferred. It will also slow down System Operations' ability to control field equipment and provide situational awareness on more of the PSE circuits.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
10/25/2019	Substation SCADA Business Case - New plan template	Document history and development of the plan	Colin O'Brien
04/17/2020	Format Update	Addition of IDOT Benefit Summary	Reid Shibata
03/25/2021	Change of Ownership	Annual Program updates based on budget adjustments	Stephen Hartnett
07/08/2021	Used and Useful Policy guidance	Add alternative and cost information	Stephen Hartnett
12/1/2021	Annual Review	Minor words and format changes	Stephen Hartnett
11/10/2023	2024 MYRP Business Plan Updates	Added Equity, removed ISP, updated program metrics, other minor updates.	Erik Engels
12/5/2023	2024 MYRP Updates	Updated Equity, Top 2 iDOT Benefits, and Program Summary Table to align with 2025-2026 project submittals	Krista Malmgren

7. SUPPORTING DOCUMENTATION

Document Name
N/A